Witness CCS - Nancy Kelly

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In The Matter Of The Application	:	Docket No. 02-035-04
Of PacifiCorp For an Investigation	:	Direct Testimony Of
of Interjurisdictional Issues	:	Nancy L. Kelly
	:	For The Committee of
	:	Consumer Services

15 July 2004

Redacted

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Introduction

Q Please state your name and qualifications.

A: My name is Nancy L. Kelly. I completed a Bachelor of Science in Economics from Idaho State University in 1982 and completed course work towards an Economics PhD from the University of Utah in 1992.

I taught for the University of Utah and Westminster College while pursuing my degree. In 1986 and again in 1988, the Idaho State University Economics Department invited me to teach a variety of courses in several non-tenure track positions.

I served as the economist in the Center for Business Research and Services at Idaho State University from fall of 1992 through spring of 1997. I was also associated in a minor capacity with Regional Service Inc. which represents clients with water and fish issues while working for the Center.

I was hired by the Committee of Consumer Services (Committee) in March of 1998 to assist it in providing input to the Public Service Commission of Utah (Commission) in its analysis of deregulation and related issues. In addition, I represented the Committee in panels providing information to the Electrical Deregulation and Customer Choice Taskforce, a legislative interim committee studying deregulation.

It was in the capacity of lead in deregulation issues for the Committee that I became involved in PacifiCorp's interjurisdictional cost allocation matters beginning in August 2000.

Q What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to support the Revised Protocol with the protections provided by the Stipulation, to place the decision to support the Revised Protocol in proper context, and to inform the Commission of areas of concern and/or incompleteness in the Revised Protocol. The Committee expects that some of these issues will be addressed by the Standing Committee and will necessarily require continuing Commission involvement, monitoring and input.

Testimony Summary and Recommendations

Q: Please provide a summary of your testimony.

A: The Committee supports the Revised Protocol with the protections of the Stipulation in order to provide the Company with greater cost-recovery certainty, given the significant resource and infrastructure investment facing it. The Committee can support the Revised Protocol with the protections of the Stipulation based on the principle of gradualism.

The Committee recommends that the Commission reaffirm that a traditional, single-system, fully rolled-in, allocation method is the ratemaking standard for determining cost causation and for evaluating whether a rate is just and reasonable; deviations from rolled-in are intended to achieve ends other than cost-causation. The Stipulation obligates the Company to provide Rolled-In results of operation through 2014. The Commission should order the Company to report Rolled-In and Revised Protocol revenue requirement results in its semi-annual results of operations and in any future rate case filings. If, after 2014, the Revised Protocol should ever exceed 1% of Rolled-In revenue requirement, the Commission should open a docket to reconsider the just and reasonableness of the Revised Protocol.

With respect to the issues that will be addressed by the Standing Committee, the Commission should do the following:

First, it should indicate its interest in a fair and balanced approach to the treatment of seasonal resources. The Commission should memorialize in the order its determination to resolve with the MSP Standing Committee the following issues (as described more fully in Exhibit 1.14): developing consistent and meaningful definitions of Seasonal Resources, including exchanges; incorporating seasonal sales and operating reserves into the treatment of Seasonal Resources; and clarifying the treatment of and ensuring the permanence of opt-out from new resources.

Second, it should require the Company to file with this Commission regarding the materiality of possible harm from load growth before ever taking a position in front of the Standing Committee.

Finally, the Commission should express its concern that events in Oregon do not cause the allocation of costs to deviate significantly from current cost causation.

Background

Q: You mentioned that you first became involved in PacifiCorp's interjurisdictional cost-allocation concerns nearly four years ago as lead for the Committee in deregulation matters. Please explain.

A: As I think everyone is aware, deregulation pressures mounted in the electricity industry in the early 1990's, just on the heels of the 1989 Utah Power and Light (UPL) and Pacific Power and Light (PPL) merger (merger). The 1992 Energy Policy Act created a new class of independent power producers, Exempt Wholesale Generators (EWGs), and required utilities to provide access to their transmission systems to enable EWGs to sell power to wholesale purchasers. The Federal Energy Regulatory Commission (FERC) issued Order 888 in 1996 requiring utilities to provide open access to all transmission services and has continued to pursue an aggressive deregulation agenda. In the same year that FERC issued Order 888, California passed its now infamous deregulation legislation, and many states passed or considered retail access legislation in the late 1990s.

In 1999 the Oregon Legislative Assembly passed Senate Bill 1149 (SB 1149), restructuring Oregon's electricity industry through broadly sketched legislation that initially allowed Oregon's non-residential customers direct access to electricity markets as of October 1, 2001, while creating a portfolio of choices for residential and other small customers who would continue to be served by the incumbent utility at cost-of-service. The legislation directed the Oregon Public Utility Commission (OPUC) to determine the details of the legislation through a rulemaking that was initiated in February of 2000 with a final rule promulgated in September of that year.

The rules required Oregon's investor-owned utilities to develop a Resource Plan through a public process to be filed 1 November 2000.[1] The Resource Plan was to divide utility generation resources between large and small customers. Each utility was to retain only enough generation in its ratebase to serve its small customers. The remaining generation was to be deregulated—removed from ratebase—either administratively or through auction. Profits (or losses) from auctioned generation would be returned (or charged) to Oregon's customers. If the utilities retained any excess generating resources, they had to pay (or collect from) Oregon's customers the difference between the market and book value of the resources over a ten-year period.

Because of the interjurisdictional ramifications of the Oregon rulemaking, PacifiCorp invited parties from other states to participate in the PacifiCorp Resource Plan Public Process (PRPPP) to help the parties in Oregon understand the interjurisdictional issues raised by the Oregon rules. I represented the Committee in a series of six meetings that were held in Portland roughly every two weeks from August though November of 2000.

The Company identified the interjurisdictional allocation problem posed by the Oregon rules in the Resource Plan filing. The quoted material below is taken from pages 2-2 through 2-3 of the filing dated December 2000. Because of the radical change in approach that implementation of the rules would have required, I have chosen to quote the entire passage.

> The Resource Plan process poses a number of new allocation-related challenges. Three are of particular significance. First…fixed shares of PacifiCorp's specific generating resources are not allocated to the various jurisdictions under current practices. PacifiCorp has a single generating system that is dispatched on an optimal basis for the benefit of all of its customers. The fixed costs of

[1] The term "Resource Plan" as part of the implementation of SB 1149 must be distinguished from an "Integrated Resource Plan." They are completely different concepts. As part of SB 1149, the term Resource Plan refers to the identification of resources or shares of resources that are permanently assigned to particular groups of Oregon customers, and by implication to all other customers in PacifiCorp's five other states. Integrated Resource Planning (IRP) refers to optimal least-cost, least-risk planning for a single unified utility system. An Integrated Resource Plan refers to the outcome of that planning process.

that single system have been allocated based upon each state's relative contribution to system peak demand and relative energy consumption and the variable costs have been allocated based upon each state's relative energy consumption as these measures vary year-to-year. The expectation in the Resource Plan rule that a portion of the Company's generating resources be "released to the competitive market" cannot be achieved in the context of the current system of inter-jurisdictional cost allocations because, among other reasons, the current system assumes load-driven dynamic changes in cost allocations whereas a permanent "release" to the market assumes a fixed inter-jurisdictional dedication of resources.

Second, the Resource Plan rule also contemplates that PacifiCorp's cost-of-service rates [for small customers] will be based upon the cost of those generating resources permanently dedicated to serving those customers as reflected in the Resource Plan. This too is contrary to past practice, where cost-of-service rates were based upon an allocation of the costs of operating PacifiCorp's entire system. No meaningful cost-of-service rate can be derived from a relatively small subset of the Company's generating resources because such a subset does not and will not operate independent from the whole.

For example, the capacity of a "slice" of PacifiCorp's generating resources corresponding to the percentage of the Company's generation costs that have historically been supported by Oregon cost-of-service customers is not large enough to cover the peak loads of Oregon cost-of-service customers. This is because in winter months, Oregon draws on generating capacity that is supported by other states, and during summer months, generating capacity supported by Oregon is available to support summer-peaking states. Additionally, for reasons such as this, the apparent average cost of operating the entire system, absent the portion of the system allocated to Oregon, will be different (and likely higher) than the actual average cost of operating the entire system. That is to say, an inappropriate balkanization of PacifiCorp's power supply assets could result in an increase in cost of service in some, if not all, of the Company's retail jurisdictions.

Third, the Resource Plan rules contemplate that to the extent Oregon's cost of service customers "outgrow" the resources allocated to them in the Resource Plan, additional resources acquired to serve them will not be included in the Company's Oregon ratebase and that such incremental requirements will be served at a market price. This is contrary to the past practice of assuming that all new ratebase additions are constructed to serve the entire system and allocated accordingly….

> In summary, the allocation challenges presented by the Resource Plan are significant. The process requires PacifiCorp to: (1) allocate generation resources to Oregon; (2) deal with the consequences of permanently fixing an allocated share for one state; (3) allocate these resources fairly among Oregon's customer groups; and (4) achieve support for the Resource Plan's decisions on these issues from each of its six state regulatory commissions.

Q: What happened to PacifiCorp's Resource Plan?

A: On 28 May 2000, wholesale power prices inexplicably shot up and remained extraordinarily high for nearly a year and a half. As a result of the extreme market dysfunction, many states that had been considering retail access decided against it, and many states that were in the process of deregulation applied the brakes in a number of ways. Oregon passed House Bill 3633 (HB 3633) on 24 May 2001, which retained a cost-of-service rate for all utility customers, not just small customers, as well as delaying open access. The legislation provided that the OPUC could waive the cost-of-service rate requirement for large customers after 1 July 2003 if the market was found to be competitive.

Q: What were the implications of HB 3633 for PacifiCorp's Resource Plan?

A: In order to provide a cost-of-service option, PacifiCorp must retain resources in ratebase. As long as a cost-of service rate is required for all its customers, the Resource Plan cannot be implemented. OPUC staff has indicated that the OPUC has no intention of waiving the cost-of-service rate requirement for its large customers. Therefore, HB 3633 permanently delays the implementation of the Resource Plan.

Q: Is that the end of the story?

A: Unfortunately, no. Because of the concerns identified above in the quoted passage from the Resource Plan, and as part of a strategic management effort to identify and manage its regulatory risk following the Scottish Power / PacifiCorp merger, the Company filed an application in all of its states in late December of 2000 (prior to the passage of HB 3633) to structurally reorganize its operations in a manner which would have been consistent with a restructured electric industry.[2] The Company filed supplemental testimony in April, May, and June of 2001, and an initial schedule was not determined until 29 August 2001. Hearings were initially scheduled for May of 2002.

Q: Please describe the Company's application.

A: The Company proposed replacing its current corporate structure with eight separate companies; a Generation Company, a Service Company, and six Distribution Companies to serve the customers in each of the six states in which it operates. The companies would have been organized under a single holding company. The transmission function would have become part of RTO West.[3] The Generation and Service Companies would have contracted with the Distribution Companies to provide services. The Generation Company was to enter into 20-year power contracts with the Distribution Companies.

In addition to the allocation concerns posed by SB 1149, the corporate restructuring application listed a number of other allocation concerns that the Company hoped to resolve as part of its corporate restructuring.

This corporate restructuring proposal came to be known as the SRP. The acronym "SRP" had its genesis in a phrase internal to the Company, "Strategic Regulatory Project;" it was later modified to reference "Structural Realignment Proposal."

Q: Were you familiar with the SRP proposal before reviewing the filing?

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[2] Electrical restructuring refers to replacing a vertically integrated industry structure with a horizontally-integrated one. A vertically-integrated utility generates power, transmits it across large distances using high voltage lines, and distributes it at lower voltages to homes and businesses in a defined geographical area. Electrical restructuring refers to breaking apart these functions. In the competitive model, the generation function would be supplied by independent power producers serving vast geographic regions. In order to facilitate a competitive market in generation, transmission must be independent of generation and distribution. Homes and businesses would be served by local distribution wires companies.

[3] Following FERC Order 2000, which required utilities under its jurisdiction to "voluntarily" join an RTO, PacifiCorp began working with other utilities in the West to develop RTO West. In July of 2002, FERC issued its Standard Market Design Notice of Proposed Rulemaking which created a large political backlash. As a result, some northwest parties have been working together to develop an alternative to RTO West. The name RTO West has recently been changed to Grid West to indicate the change in concept. Grid West would be phased-in with the RTO West design as the goal of the final phase. However, the concept has not yet received state or FERC approvals.

A: Yes. PacifiCorp initially presented the idea to participants of a PRPPP meeting 26 September 2000. The topic was again on the agenda at the last meeting of this group, 2 November 2000. In particular, the reaction of the Oregon small customer representative was sought, and he provided cautious approval.

Q: Did you participate in the SRP proceeding?

A: Yes. I led the Committee team in assessing the impact to small customers from implementing the Company's proposal.

Q: What became of the Company's SRP?

A: The reaction to the proposal, at least in Utah, was quite negative for many reasons.

First, electrical restructuring had been considered by the Utah Legislature and studied by a legislative subcommittee, the Electrical Deregulation and Customer Choice Taskforce, and had been rejected. As a result of the Western market meltdown, the Taskforce turned its attention from contemplation of retail access to consideration of how to encourage an adequate power supply in Utah. The last meeting of the Electrical Deregulation and Customer Choice Taskforce was held 20 November 2000. The 2001 General Session passed House Bill 244 changing the name of the taskforce to the Energy Policy Taskforce to reflect its new purpose. Changing the corporate structure of the Company to coincide with a market structure that had been rejected by the Utah legislature would have been contrary to legislative direction.

Second, approval of the application would have required the Commission to relinquish jurisdiction over all but distribution costs.

Third, it appeared to analysts in the Utah community that the SRP had the strong possibility of increasing overhead and net power costs which would result in higher rates. Integrated resource planning would have been supplanted by individual state planning, undoing the merger benefits over time and resulting in a suboptimal system.

Finally, the implementation of the concept would have radically changed cost-of-service regulation, and it was not considered feasible. Twenty-year contracts would have replaced traditional rate cases. Who was to negotiate the 20-year contracts for Utah's customers was not clear.

For these and other reasons, it became evident that PacifiCorp did not have the support required to move the proposal forward in Utah. Ultimately, PacifiCorp suspended its SRP application in favor of moving forward with a Multi-State Process (MSP).

Q: How did that come about?

A: The cross-over from SRP to MSP evolved over a five-month period. It had its genesis in a Utah idea, but the ultimate process was nothing like what Utah parties had discussed.

Some Utah parties, including the Committee, were sympathetic to at least two of the issues that PacifiCorp had identified in its SRP filing. The Committee believed that resolution could require multi-state cooperation to address "interstate issues arising from the implementation of Oregon's SB 1149 rules, and cost allocation of new plant investment."[4] While the passage of HB 3633 had moderated the immediate need to implement PacifiCorp's Resource Plan, some parties in Utah thought dialogue with Oregon representatives regarding implementation of SB 1149 was sensible. However, equally important to both the Committee and the Division of Public Utilities (Division) was ensuring that PacifiCorp adequately plan to serve its system at least-cost and that it implement its plan in a timely manner. This, too, seemed to require dialogue with other states.

Q: I understand your concern regarding the implementation of SB 1149 from your earlier discussion. Please explain your comment with regard to resource planning.

A: One of the stated purposes of the 1989 merger was to position the merged company as a competitive seller of wholesale power.[5] This was reflected in the

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[4] December 13 2001 *Meeting Notice and Agenda* (See CCS Exhibit 1.1)

[5] Immediately following the merger, despite its large surplus, PacifiCorp acquired additional resources to increase its operating flexibility, lower its long-term total system costs, and position itself to become an active participant in the wholesale power market. The purchases of Cholla Unit 4 in Arizona and pieces of Craig and Hayden plants in

merged Company's stated strategic business plan and actions immediately following the merger. From the time of the 1989 merger until May of 2000,[6] the Company had been a net seller into the western wholesale market.

However, as deregulation pressures mounted in the mid-1990s, the Company changed its strategy and became reluctant to add additional firm generating capacity. PacifiCorp avoided or reduced the acquisition of long-term firm resources, first citing fears of stranded cost recovery, and later cost recovery concerns in general, noting Oregon's expressed intention to not ratebase additional plant, and later still the opposition of Oregon and Washington parties to acquiring resources to meet "Utah" loads.

Instead, PacifiCorp relied on the short-term market to meet its retail and wholesale load obligations. It did this despite Utah Commission Orders that declined to acknowledge two of the utility's Integrated Resource Plans (IRP). Comments to the Commission had cited, among other reasons for not acknowledging the IRPs, the substantial market risk inherent in the Company's Action Plans.

By the summer of 2000 the system was short in the summer and significantly deficit in the eastern control area.[7] When deregulation backfired and a combination of a low hydro year and market manipulation led to skyrocketing electricity prices, PacifiCorp was compelled to buy in an expensive market. It quickly added peaking units in the Utah bubble to hedge against the market dysfunction. Although a past IRP had indicated the need for

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Colorado brought with them transmission rights to access southwest market hubs that benefited the system as a whole.

The merged Company appears to have pursued its strategy of extending its reach into new markets because of then current western market conditions. The West was overbuilt, and the glut of power could be cheaply accessed, putting on competitive pressure on sellers. The extensive transmission system provided the necessary flexibility to increase the merged Company's competitiveness as a seller as well as a buyer.

[6] When the Company sold its 636.5 MW interest in its Centralia coal plant in May of 2000, the PacifiCorp system switched from balanced to deficit.

[7] Utah, Idaho and Wyoming loads are in the eastern control area. Oregon, Washington and California loads are in the western control area.

a Combined Cycle Combustion Turbine (CCCT) as early as 2000, lead-time did not allow for the addition of cheaper CCCTs.

Both the Committee and the Division were adamant that PacifiCorp implement "effective" IRPs, that is, that it undertake a serious planning effort and that it implement the acknowledged Action Plans. The Company, however, continued to express concern that other states would not pay for new resources.

Q: I now understand your concern with both SB 1149 and the need for effective resource planning and why you thought resolution of these issues could require discussion among the states. How did Utah parties proceed?

A: During a 20 November 2001 SRP Technical Conference, the suggestion was made to organize a meeting with other states to discuss the implications of Oregon's deregulation and the acquisition of new resources. The Committee and the Division developed an agenda for a multistate meeting which was held 13 December 2001. PacifiCorp organized the meeting and Portland and Salt Lake City were video linked. A PacifiCorp representative facilitated. The meeting announcement and agenda are attached as CCS Exhibit 1.1. The meeting notes are attached as CCS Exhibit 1.2 As you can see from the agenda, whether the Company was even to be involved was an open question to the agenda drafters.

Q: What was the outcome of the meeting?

A: A subgroup was formed to design a multi-state forum. At the urging of the Company and the Oregon representative, membership was limited to one participant from each state. The Committee was closed out of this process. When the multistate forum reemerged at a public meeting 6 February 2002, both the problem statement and process were quite different from what the Committee had supported during preliminary discussions within Utah. While the Committee had supported informal information exchange on the topics of SB 1149 and Integrated Resource Planning, the problem was now redefined as "the current allocation of PacifiCorp's costs and revenues" and the goal to achieve a "global resolution." The Draft Goal Statement from the 6 February meeting is attached as CCS Exhibit 1.3.

On 5 March 2002, the Company filed with the Utah Commission an "Application to Initiate an Investigation of Inter-jurisdictional Issues." It proposed an issues list and a formal process to be directed by an independent "Special Master", Robert Hanfling.

After considering comments from parties regarding PacifiCorp's application, the Commission issued an Order on 3 April 2003. In the order, the Commission granted the application to examine interjurisdictional issues but expressed no judgment regarding the issues to be examined. It allowed PacifiCorp to use Mr. Hanfling as a facilitator but not as a "Special Master". The Commission specifically directed that "there be initiated a multi-state process ('MSP') to afford interested parties from all of the Company's jurisdictions an opportunity to identify and analyze inter-jurisdictional issues facing PacifiCorp, and to seek consensus concerning them."[8]

Q: Please summarize the MSP.

A: As I see it, the MSP can be divided into three distinct phases: (1) April through December of 2002; (2) January 2003 to the filing of the Protocol in September of 2003; and (3) the Protocol filing to the present.

Q: Please describe what you have termed the first phase.

A: Certainly. The first meeting was held 10-12 April 2002 in Boise Idaho. Stakeholders from five of PacifiCorp's six states (California did not participate), with differing directives from the five participating state commissions, met with the Company, and Robert Hanfling as a facilitator, to "investigate" interjurisdictional allocation issues.[9] From the beginning differences in approach were apparent.

[8] Public Service Commission of Utah, Order on PacifiCorp's Application to Initiate Investigation of Interjurisdictional Issues, In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues, 3 April 2002, p. 2.

[9] Utah was represented by the Utah Public Service Commission Advisory Staff; the Utah Division of Public Utilities; the Utah Committee of Consumer Services; the Utah Association of Energy Users Intervention Group; the Salt Lake Community Action Program; the Cross Roads Urban Center; and the Federal Executive Agencies.

While Utah parties were participating to share information, conduct an investigation, and try to resolve issues based on a principled approach to each item, the Oregon parties, with the apparent support of the Company, and the facilitation of Mr. Hanfling, were there to negotiate a “package” deal. While Utah parties thought the main issues on the table were (1) how to collectively address Oregon’s deregulation in a manner that would not harm the Company or any of its states and (2) how to incent the Company to conduct an effective IRP to protect all of PacifiCorp’s customers from the uneconomic costs of delayed decision making, the hot buttons for other parties, particularly Oregon and Washington, were Utah’s formal adoption of Rolled-In and Utah’s load growth. While Utah parties thought the uneconomic costs of the spot market purchases to meet the summer peak and the hasty additions of Gadsby and West Valley were the result of the Company’s delayed planning, Oregon parties, in particular, viewed these costs as caused by Utah’s load growth.

Issues for Oregon and Washington included: Utah’s load growth and the cost of meeting the eastern summer peak; a carve-out of the hydro resources for the benefit of the northwest states; the situs treatment of special contracts; and the refunctionalization of transmission assets. Idaho and Wyoming were willing to participate in the process but apparently had no issue other than to assure that they were not significantly harmed by the outcome.

The main issue for the Company was to assure 100% cost recovery of new and existing resources. It believed recovery was threatened by differences in the energy policies and politics of its states, particularly on a west vs. east basis. It provided a list of issues that it wanted addressed in a global package.

Utah parties proposed that the factual basis for the multiple concerns of both the Company and the northwest parties be examined and then solutions crafted to address real problems. However, that was not the course taken. Driven primarily by PacifiCorp and the Oregon stakeholders, and facilitated by Mr. Hanfling, a long list of potential problems was developed in a brainstorming session and parties were asked to submit their “must haves.” Participants were then directed to create solution packages that would address the list of issues and stakeholder demands.

Oregon and Washington parties asserted that the exclusive benefit of the Company-owned hydro facilities and the Mid-Columbia Contracts and protection from Utah's load growth were must-haves for them. OPUC staff began submitting proposals for analysis.[10]

The Utah parties objected to this approach and emphasized the need to develop a common factual basis for individual state decision-making. We stated repeatedly that, if Utah has a "must have," it is sound analysis. The response was to move along two tracks simultaneously; analysis was to be developed concurrently with solution packages.

A satisfactory examination of the factual basis of state concerns had yet to occur by the end of the seven 2002 meetings. Although extensive modeling had been undertaken that assigned resources and allocated costs in various ways and examined the revenue requirement impact on each state, no one had analyzed the presumptions underlying the requests for alternative model runs.

Towards the end of phase one, a proposal was made to structurally split the Company for cost accounting purposes. The basis for the split would be the Company's two control areas. The cost of the resources in the two control area would be directly assigned to the loads within those control areas, and any power transfers would be credited to the control area providing the power and charged to the control area using the power.

Utah parties objected to this approach for both fundamental and practical reasons, desiring to demonstrate that a traditional approach to cost allocation could address the range of concerns while maintaining regulatory principles and minimizing unintended consequences. By the final scheduled meeting, no

[10] Proposals included: hourly energy cost allocation; different weighting of demand and energy for base load, intermediate, and peaking resources; divisional assignment of hydro using load decrements; including Mid-Columbia with load decrements; DSM Adjustment: reallocated costs and benefits system-wide; allocating all fixed costs on energy generation; allocating fixed generation costs -- allocating 1/12 to each month, and then allocating on monthly energy and CP.

consensus had been reached. The process was extended into phase two. PacifiCorp agreed to work with Utah parties to address issues within a traditional regulatory framework as well as to further develop the structural split with the input of northwest parties. For reasons that will be developed below, the Utah approach was termed the "Dynamic Alternative" and the structural split, the "Hybrid."

Q: Please describe what you mean by a traditional regulatory framework.

A: Earlier in my testimony I quoted extensively from the Oregon Resource Plan. That section describes the way costs are traditionally allocated based on use of system resources. As I will discuss again later in my testimony, a key regulatory principle is that those who cause costs should pay them. In order to capture cost-causation, a cost allocation method should reflect the actual operation of the current utility system. PacifiCorp's diverse system is operated as a single unified system to meet the needs of its many customers.[11]

Under traditional regulation, utility-related plant or services that are used by a particular jurisdiction are directly assigned, for example distribution assets. However, other utility resources or services are jointly used; their costs must be allocated based on proportional use. As state use grows or declines, so will its share of total system costs. Because a state's share of system costs will continue to fluctuate with its use of system resources in the Utah proposal, this approach to resolving interjurisdictional issues and allocating system costs is referred to as the "Dynamic Alternative."

Q: What are the benefits of a traditional approach to ratemaking?

A: The first is the benefit of cost-causation. If costs are allocated so that those who cause the costs pay, the method is fair and efficient. Traditional rate-

[11] The PacifiCorp system is comprised of two control areas covering a vast geographic region with diverse weather patterns, load patterns, and covering two time zones. The PacifiCorp system has firm transmission access from the Pacific Northwest—including the liquid markets at Mid-Columbia and the California-Oregon Border—to Montana, Colorado, and the Desert Southwest markets in Arizona. PacifiCorp also has non-firm economic transmission access throughout the West, from British Columbia to California, northern Mexico and west Texas. As a result of its transmission reach, it has great flexibility as both a buyer and seller of power. It can sell excess on one side of its system and buy on the other depending on market conditions, demand conditions, generation availability, etc.

making has the additional benefits of hedging customer risk, administrative simplicity, and regulatory stability.

Q: Given the benefits of traditional cost allocation, why didn't all multi-state participants support its use? Why were other options developed?

A: I think the reason is fourfold. First, not everyone agreed that the PacifiCorp system is operated as a unified single system.[12] Second, the load growth issue had not yet been investigated and none of us knew how well traditional rate making worked in fairly distributing the costs of load growth at that point in time. Third, some of the northwest participants have a belief in entitlement of particular resources based on history. While Utah considers current cost-causation essential to fairness, some of the northwest participants look to premerger history to determine fairness. Finally, the Company was looking for a permanent solution to potential state policy differences to minimize regulatory risk to shareholders. A structural assignment is more permanent than the incremental approach to regulation preferred by Utah participants.

Q: Briefly explain the structural split concept.

A: The Company, Oregon and Washington parties, and Idaho staff, who initially advanced the idea, focused their efforts on developing an allocation approach that would create two divisions based on the Company's current control-area boundaries for the purposes of cost-allocation. It would, in a sense, demerge the Company for the purpose of assigning resources and allocating costs.[13]

Costs for each division would depend on the cost of the resources assigned to the control area and would then be allocated to the states within the control area based on each state's use. The cost of new resources would

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[12] The Washington parties, in particular, expressed that the transmission constraints between the control areas was evidence that PacifiCorp was not a unified single system. As discussed later in testimony, Commissioners requested state staffs to develop a common factual record on this point. This did not happen.

[13] The western division would include PacifiCorp's California, Oregon, and Washington service territories, and the eastern division would include its Idaho, Utah and Wyoming service territories. These would differ from the original Pacific Power and Utah Power divisions: both Pacific Power and Utah Power previously served parts of Wyoming, but all Wyoming customers would be assigned to the eastern division.

be shared by the states within the control area where the resource was sited, again based on each state's use. Because this approach to allocating system costs has fixed assignment as well as dynamic aspects, it became referred to as the "Hybrid."

In actuality, PacifiCorp would continue to operate a single system and power would continue to flow across control area boundaries, requiring complex accounting, referred to as "interchange accounting", to ensure that both the benefits and costs of the resources assigned to each control area, as well as market purchases and sales, were properly tracked and allocated.

Q: Was there support for this approach?

A: The Oregon and Washington parties strongly advocated the Hybrid as meeting their policy objectives. They receive the costs and benefits of the hydro resources and have "structural" insulation from the costs of Utah load growth under the Hybrid. It also provided them with surplus resources which were "sold" to the eastern control area and credited back to them, providing significant reductions in revenue requirement over Modified Accord and other proposals. The Company preferred the Hybrid, at the time, because it believed it minimized its regulatory risk by grouping states with seemingly similar energy policies. The Idaho Commission staff preferred this approach because it addressed the northwest's must-haves and resolved the resource acquisition issues that could arise from divergent state energy policies.

Q: I take it from earlier discussion that the Utah parties, generally, were not in favor of the Hybrid.

A: I think that is an accurate statement. There may have been one or two individuals that were initially open to the approach, but as discussion and analysis continued, the Hybrid did not find favor within Utah.

Q: What were the Committees concerns with the Hybrid?

A: Our concerns were extensive. The results from the Hybrid did not reflect current cost causation, the original proposed split of resources was extremely unfair, the Hybrid was highly sensitive to market conditions, and the interchange accounting methodology had fatal flaws. The Committee MSP

Team completed and distributed an in-depth critique of the proposed interchange accounting methodology in late May of 2003. A copy is attached as CCS Exhibit 1.4.

Q: Please describe the activities in Utah during the spring of 2003.

A: In early January, with the assistance of the Company, Utah parties began an in-depth study of the cost characteristics of the system, including investigations of: rate differentials across jurisdictions; the northwest belief that Utah is shifting the cost of its growth to other jurisdictions; and the factual basis for the northwest claim to a "hydro endowment." In addition, Utah parties began fleshing out their dynamic proposal by developing methods within the traditional regulatory framework to respond to other MSP concerns, including Oregon's deregulation initiative and the assignment of special contract customers' costs and revenues. The resultant Utah Dynamic Proposal was distributed to MSP participants on 12 June 2003. A copy is attached as CCS Exhibit1.5.

Q: Did anything else of significance happen during the spring of 2003?

A: Utah Commissioners attending the annual meeting of the Western Conference of Public Service Commissioners in Lake Tahoe the week of 23 June 2003 took the opportunity to discuss the MSP with commissioners from Oregon, Washington, Idaho, and Wyoming. As a result of those discussions, Utah and Oregon staffs were directed to work together to prepare a common factual understanding of three key areas of question: impact of disproportionate load growth; benefits of system operation; and consequences of divergent state energy policies for new resource acquisition.

The Company responded by immediately launching an investigation into the load growth issue. Both the preliminary load growth results revealed 7 July 2003 and the results of the study requested by Oregon staff and reviewed in Las Vegas 16 July demonstrated that current load-based allocators are shifting an appropriate share of the cost of Utah's load growth to Utah.

Q: You mentioned a multistate meeting held in Las Vegas in July of 2003. Please briefly discuss what occurred at that meeting.

A: The entire multi-state group met in Las Vegas 15-17July 2003, apparently for the last time. Utah parties had understood the purpose of the meeting to be to review the results of the Company's investigation into the three issue areas, as directed by the Commissions, and to discuss the relative strengths and weaknesses of the dynamic and hybrid alternatives in light of the new analysis with the hope of moving toward one of the two proposed solutions. However, the meetings were not organized well to achieve that end. Too much opportunity was provided to restate and further polarize positions rather than to develop a common factual understanding. The meetings ended a day early prior to a full review of the Company's analysis or a satisfying discussion of the last two issues.

Q: So, things were just left hanging?

A: Not completely. The Company indicated it would consider what it had heard and what it had learned from its investigations, and it would propose a single allocation method in a filing sometime early in the fall of 2003. It filed a "Motion for Ratification of Inter-Jurisdictional Cost Allocation Protocol" (Protocol) on 30 September 2003.

Q: Did this end phase two.

A: It did.

Q: Describe the Protocol.

A: The Protocol specified the cost-allocation treatment for existing and new resources. It mixed aspects of traditional rolled-in cost allocation with the direct assignment of certain categories of costs to specific jurisdictions in a manner similar to the Hybrid. It began with a dynamic allocation approach but provided significant exceptions. The costs of the former PPL hydro resources and the Mid-Columbia Contracts were directly assigned to the former PPL states, and the costs of the Huntington coal plant were directly assigned to the former UPL states. The Protocol created a seasonal resources category that allocated the cost of certain resources on seasonal loads rather than on annual loads. With respect to new resources, the Protocol provided that if any state disallowed costs of resources added to meet individual state policy, such as might be required by a Renewable Portfolio Standard, the disallowed costs would be directly assigned to the state who required the resource. And, Oregon was offered a “one-time irrevocable opt-out” on the first major coal plant addition.

In addition to addressing the cost treatment of generation resources, the Protocol specified the cost allocation for a number of possible contingencies including: direct access in Oregon; special contract discounts; gain or loss on the sale of an asset; and significant load gain or loss. It addressed the allocation of transmission costs should an RTO be formed, and it discussed how transmission costs would be allocated should FERC reclassify transmission assets. Finally, the Protocol established a method for resolving future disputes through a standing committee.

Q: Typically, once a formal proceeding is filed, a schedule is determined and parties prepare to address the filing. Did this happen?

A: Yes. A schedule was set last fall that included technical conferences, a discovery schedule, the unusual circumstance of at least one scheduled meeting among Commissioners from the participating jurisdictions, testimony due dates, and the current hearing schedule. The Committee undertook developing data requests and digging into the content of the Protocol. However, as has been typical of the MSP case, the content, process, and schedule continued to shift in a flurry of activity. Only the hearing dates have remained firm.

Q: Please explain what you mean by the content continued to shift.

A: In producing a single agreement, the Protocol appeared to have been a failure. Neither Oregon parties nor Utah parties liked the concept of a coal endowment or a coal opt-out, although reasons varied. In addition, the Oregon parties strongly objected to the lack of structural protection in the Protocol to the costs of Utah load growth, and Utah parties were adamantly opposed to inclusion of the Mid-Columbia Contracts in any hydro adjustment and were distressed that the Company did not use methods developed in the Utah Dynamic Alternative to address many of the issues on the table for which solutions had already been found that were thought to be superior to the Company’s approach.

Parties in both Oregon and Utah conveyed these reactions to the Company. The Company's response was to encourage negotiation between the two states and to seek an alternative way to calculate a hydro endowment. Oregon parties advocated a load-decrement approach to a hydro adjustment, and the Company was actively developing this over the objections of several of the Utah parties, when work on the load growth front revealed a fatal flaw in the load-decrement approach halting its further development.[14] Shortly before the final multistate meeting held in Boise on 27-28 April 2004, the Company introduced a new approach which they call the Embedded Cost Differential.[15]

Q: You stated that the Company encouraged negotiation between the states. Did this take place?

A: Division staff and OPUC staff met regularly in Boise Idaho throughout the winter and spring of 2004, hosted by Idaho staff. Division staff indicated to other Utah parties that their intention in participating in the meetings was to share information with OPUC staff; however, they also explained that the OPUC staff did believe the meetings to be negotiations. The Division provided other Utah parties with notes from each of the meetings. As a result of those meetings, Division staff suggested to other Utah parties that we not spend time in our Utah Technical Conferences analyzing either the coal endowment or the coal opt-out because those were considered to be off the table. It was at that point in the process that we realized that major elements of the Protocol were still in flux.

Q: So, the coal endowment and the opt-out on the first coal resource for Oregon were gone, and the hydro-adjustment was in flux. Were there other moving pieces?

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[14] With a load-decrement hydro endowment, Utah picks up more than 100% of the cost of its growth when it is the fast growing state. However, when Oregon is the fastest growing state, Utah still picks up 63-66% of the cost of Oregon's load growth while Oregon picks up but 40%.

[15] The Embedded Cost Differential hydro-adjustment is addressed briefly later in Testimony.

A: How to create a hydro-endowment that would be large enough to satisfy Oregon parties and not saddle Utah rate payers with a politically unsupportable cost seemed to be the main focus of activity directly related to the Protocol. The Company seemed less receptive to the Utah critique of other of the components of the Protocol, for the most part sticking by the approach they had taken. The Company was however working hard to address the load growth issue.

Q: Please discuss the load growth issue and related activity.

A: Activity related to load growth began with Oregon but shifted to Utah over the eight-month period from the last Las Vegas meeting in July of 2003 to the last Boise meeting in April of 2004.

Q: Please describe Oregon participant-sponsored activity.

A: Oregon parties were unconvinced by the results of the load growth studies that were conducted just prior to the last Las Vegas meeting, and the OPUC staff continued to request a number of model runs to try to estimate potential harm from Utah's growth. Initially the studies focused on harm from Utah's current peak load growth but later evolved to address harm from Utah's relatively faster growth, if sustained over time.

In order to structurally insulate Oregon, Oregon parties advocated developing a tiered allocation method for allocating the costs of new resources. At the request of Oregon parties, the Company began developing a method which would allocate the costs of new resources differently than the costs of existing resources. Each time a new resource is added, a new tier of rates is established.

Q: What became of the tiered rate allocation mechanism?

A: The Company came to realize the extreme complexity of tiering and halted development. The Company also understood that tiered rates would probably not fly in Utah.[16] Oregon agreed to set the issue aside temporarily but expects

[16] As discussed later in my testimony, the Utah Commission has established a compelling precedent for using current costs rather than historic costs in setting rates. Tiering allocates costs on historic rather than current use.

a structural mechanism to be developed in the future. I discuss this later in my testimony.

Q: What analysis of the load growth issue took place in Utah?

A: In response to Commission direction, Utah parties, primarily the Commission Advisory staff and the Committee of Consumer Services, with the assistance and input of the Company, sought to analyze the risk to other jurisdictions from disparate state load growth and to place the potential harm to other jurisdictions in the context of the benefits of single system operation and planning. [17]

The load growth study is attached as CCS Exhibit 1.6. It remains a draft. We never quite completed the work before the process shifted, requiring that we scramble in other directions and not complete our analysis.

Q: What did you conclude?

A: The Utah parties concluded that a Rolled-In Allocation method fairly distributes the cost of load growth to the growing state and that the risk to slower growing jurisdictions from disparate load growth is small. Given the information that I have reviewed, it is my opinion that on balance Utah fully pays for its load growth and will as long as the Company develops and implements an effective IRP.

Q: You stated that the report remained a draft because the process shifted. Please explain this shift in process.

A: The Committee received a memo from Mr. Robert Hanfling via email 6 April 2004 informing us that he had been asked to "rejoin the MSP in a more active role as a 'Mediator.'" The memo informed us that the Mediation Process had the "endorsement" of our Commission and "the goal of filing a comprehensive settlement of MSP issues on or before May 10, 2004." He proposed an aggressive schedule to accomplish the stated objective, and he indicated that the Company would be filing a draft proposal the following day. Two additional memos distributed on 7 and 8 April 2004 modified the initially proposed schedule. Ultimately two multistate meetings were held. The first meeting was held 15-16 April in Salt Lake City. The final multistate meeting was held in

[17] The Division was focused on preparing for its meetings with OPUC staff.

Boise Idaho on 27 and 28 April 2004. The three referenced memos are attached as CCS Exhibit 1.7.

Q: Do you know how Mr. Hanfling became reinvolved and how the process became a more formal mediated process?

A: No. I am not clear on whether it was at the behest of an Oregon Administrative Law Judge or at the behest of the Company that Mr. Hanfling became reinvolved. I have heard conflicting answers from seemingly credible sources.

Q: Did the Committee have the opportunity to provide input regarding the change in process and the move to mediation?

A: No.

Q: Do you know the process through which the Commission approved the Mediation Process?

A: No.

Q: How did the shift in process affect Utah activities?

A: The schedule was extremely tight, particularly with other ongoing responsibilities, and all real work and solid analysis halted and was replaced by numerous meetings. In addition to the scheduled meetings above, Mr. Hanfling met several times with individual Utah parties, and the Utah parties met together on several occasions to try to complete our load growth work and respond to the requirements of the new schedule.

While we had been attempting to work within Utah to build a consensus regarding the most important issues and largest dollar components of the Protocol first, our ability to build a Utah consensus based on objective factual information, grounded in principle was interrupted.

Q: What became of the Mediation Process?

A: Parties met in Salt Lake City in mid-April and again in Boise in late April. The provisions of PacifiCorp's draft document were reviewed. The draft is little different from the Revised Protocol which is the subject of this proceeding. Utah's load growth was the focus of much conversation, and Utah parties effectively countered Oregon's assertions of harm. However, the validity of our position seemed to have little or no effect. Ultimately, differences between the parties were too great, the cost to Utah of conceding to northwest demands too high, and the meeting ended with no agreement.

Q: What happened after the Boise meeting?

A: Settlement discussions between the Company and Utah parties to mitigate the cost to Utah from the impact of the Revised Protocol and to modify Revised Protocol language were entered into. The Revised Protocol and Stipulation were filed 25 June 2004. They are the result of that process.

Q: Does that end phase three?

A: It does.

Support of the Revised Protocol with the Protections of the Stipulation

Q: Please describe the Revised Protocol.

A: The Revised Protocol is a method of apportioning the costs and wholesale revenues associated with PacifiCorp's generation, transmission and distribution systems among the six states in which PacifiCorp operates. It is an attempt to cover the universe of potential interjurisdictional allocation differences and provide a common road map for all states. If followed by all, it would, in the long run, result in the opportunity for PacifiCorp to recover all of its prudently incurred costs and investments and earn its authorized rate of return. In addition it provides a forum to resolve new interjurisdictional issues should they arise.

Q: Why is a common method to apportion PacifiCorp's costs necessary?

A: PacifiCorp operates a single system to serve customers in six states. In order to remain a viable business, over the long-run it must recover its expenses and investments from the customers in those states and earn its authorized rate of return on its investment. A common apportionment method provides the utility the opportunity to recover its prudently incurred costs and earn its allowed rate of return.

Q: Does PacifiCorp have a common apportionment method today?

A: No. At the beginning of this process, there were two methods in use, Utah's formally adopted method, Rolled-In, and Modified Accord. Utah adopted

Rolled-In in 1998 and implemented a five-year phase-in.[18] In that same year Idaho Commission Staff recommended a five-year transition to Rolled-In. California, Oregon, Washington, and Wyoming were using Modified Accord, the last method developed through the PacifiCorp Interjurisdictional Taskforce on Allocations (PITA).[19] However, two of these states, Wyoming and Oregon, were considering possible changes. In August of 2000, a representative of the Wyoming Advisory staff indicated at a PRPPP meeting in Portland that Wyoming would be moving to Rolled-In, even though its costs would increase to do so. Oregon's status was unclear because of the passage of SB 1149 in 1999 and the Rules developed by the Oregon Public Utilities Commission to implement the legislation. However, the Company continues to use Modified Accord in reporting results of operation in Oregon.

Q: Please describe the Rolled-In method:

Rolled-In is the allocation method that is consistent with single system planning and operation and the principle of cost causation. In its April 1998 Report and Order in the 1997 Utah Interjurisdictional Allocation case, the

[18] While the Utah Commission formally adopted Rolled-In 16 April 1998, it established Rolled-In as the standard method for determining Utah's revenue requirement consistent with single system operation and planning and the principle of cost causation in the first phase of the 1990 rate case. A lump sum amount to achiever merger fairness was added.

The 1997 test-year rate case, Docket No. 97-035-01, resulted in a refund to customers of $111.49 million because of a rate freeze imposed by the Utah legislature. In that case, the Commission determined that $71.24 million was the remaining amount of the fairness adjustment. It used the refund to buy out the five-year transition to Rolled established in Docket No. 97-035-04. (See: Public Service Commission, Report and Order, In the Matter of the Investigation into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Company, Docket No. 97-035-01, 4 March 1999, pp 55-64.)

[19] Three allocation methods were developed and adopted by PITA: Consensus, Accord, and Modified Accord. Accord was adopted by PITA in January of 1993 and Modified Accord in June of 1997. Each method moved successively more costs from divisional assignment to a more fully rolled-in system assignment. Although Modified Accord included a hydro endowment as a fuel adjustment, four of the seven states supported ending the hydro endowment at some future time. (See June 1997 PITA minutes pp. 9-10.)

Commission equated Rolled-In with the Standard Apportionment method which it described in that order. [20]

The standard apportionment method takes booked utility costs and spreads them to the states it serves through three steps: functionalization; classification; and allocation. The goal of apportionment is to achieve equitable and efficient results.

As mentioned earlier in my testimony, a key regulatory principle is that those who cause costs should pay them. If costs are apportioned based on cost causation, the outcome is equitable and efficient. For certain categories of costs, determining who "caused a cost" and therefore who should pay is simple. Certain costs are incurred to serve customers in one jurisdiction only. In such cases, the costs can be directly assigned to that jurisdiction. For example, new distribution plant investment along the Wasatch Front benefits Utah customers only, so such costs can be directly assigned to Utah. However, other categories of costs are incurred which benefit customers in all states. In this case a share of the costs must be allocated to customers in each state. Rolled-In allocates the costs of joint-use resources to each state based on a state's contribution to system peak demand and annual energy use, thereby capturing cost-causation.

Q: Please describe Modified Accord.

A: Modified Accord begins with a rolled-in allocation of joint costs based on use, but differs from Rolled-In in two respects. First, both the fixed and non-fuel operating costs of premerger plant are divisionally assigned. Second, Modified Accord includes a Company-owned hydro adjustment calculated as a fuel adjustment for the benefit of the former PPL states. The divisional assignment of premerger plant was thought to benefit the former PPL states because of its relatively lower cost of service. However, the benefit was expected to disappear in the 2015 time period as the premerger plant retired and was

[20] Public Service Commission, Report and Order in the Matter of a Proceeding to Establish An allocation Methodology to Separate PacifiCorp's Assets, Expenses, and Revenues Between Various States, Docket No. 97-035-04, 16 April 1998, pp 2-4.

replaced by new post-merger resources. The hydro adjustment on the other hand was designed to continue indefinitely because it compared the operating cost of the hydro resources to the operating cost of the system steam resources. As additional steam plants are added to the PacifiCorp system they became part of the fuel adjustment calculation.[21]

Q: How does the Revised Protocol differ from either Rolled-in or Modified Accord?

A: The Revised Protocol begins with traditional ratemaking (Rolled-In) and then makes four significant adjustments. First, it provides a Company-owned hydro cost adjustment, as does Modified Accord, but the method differs from all previous hydro adjustments. Second, it allocates to Oregon and Washington a substantial share of two of the low-cost Mid-Columbia Contracts. Oregon receives the largest share. Third, it assigns to each state the cost of existing Qualifying Facility (QF) contracts approved by each state. Since January of 1993 when the Accord method replaced the Consensus method, wholesale power contracts, including the Mid-Columbia and the QF Contracts have been fully rolled-in. Fourth, it allocates the costs of certain resources on seasonal loads rather than on annual loads. This approach was new to the Protocol. Costs were previously allocated on annual loads.

Q: You mentioned that the Revised Protocol was an attempt to anticipate the universe of potential cost allocation differences and provide a common method for each of those situations. Is there more to the Revised Protocol than a hydro adjustment, a Mid-Columbia Contract adjustment, situs assignment of QF contracts and the introduction of seasonal resources?

A: Yes. Those four elements of the Revised Protocol are primarily responsible for the cost difference between it, Rolled-In and Modified Accord. However, there is more to it, since it fully specifies the cost treatment for all existing assets, resources and purchase and sales contracts, and attempts to

[21] The Utah Commission rejected Modified Accord in Docket Number 97-035-04 as not reflecting cost causation.

address the cost treatment for all potential resources and purchase and sales contracts. The Revised Protocol specifically addresses the cost allocation of the following:

- Oregon's Direct Access;
- Renewable Portfolio Standard;
- Special Contracts;
- New Qualifying Facilities;
- The loss or gain on the sale of an asset;
- Load loss;
- Disparate load growth among states;
- Refunctionalization of transmission.

Finally, it makes provisions for addressing interjurisdictional disputes through the creation of a Standing Committee to be comprised of a member or designee of each Commission.

Q: Does the Committee support the Revised Protocol?

A: Without the protections afforded by the Stipulation the Committee cannot support the Revised Protocol.

Q: Please explain.

A: The Revised Protocol is considered by PacifiCorp to be a compromise between Utah's insistence on traditional ratemaking consistent with integrated single system planning and operation and Oregon's and Washington's insistence on a hydro endowment, the exclusive benefit of the Mid Columbia Contracts, and protection from the costs of Utah load growth. PacifiCorp also understood certain parties in Utah to signal a willingness to accept up to a 2% cost shift in order to reach an agreement.[22] It crafted the Revised Protocol to be responsive to these demands and limitations.

[22] Utah parties had indicated during the MSP process that we would accept no more than a "fair share" cost shift should there be a cost causal basis for a cost shift. The Committee understood the Fair Share to be a proportional share of the difference between Rolled-In and Modified Accord as first proposed by a PacifiCorp representative, Dr. Rodger Weaver, during the PRPPP. This is explained in greater detail later in my testimony.

From the Committee's perspective it is too costly, and the timing of costs and benefits is unacceptable. In addition, the Committee questions its durability.

Q: Is it an accurate statement that by ratifying the Revised Protocol, the Commission will rely on an apportionment method in future rates cases that increases Utah's revenue requirement?

A: Yes. Three of the four components of the Revised Protocol that change the allocation of the costs of existing resources from how they are allocated under either Rolled-In or Modified Accord increase Utah's revenue requirement, at least in the early years: the calculation of the Company-owned hydro adjustment, the treatment of the Mid-Columbia Contracts, and the specification and inclusion of the seasonal resources. The Company-owned hydro adjustment increases Utah's revenue requirement in the early years and lowers it in the later years of the study period. The Mid-Columbia Contract adjustment and treatment of seasonal resources increases Utah's revenue requirement in all years.

The situs assignment of the existing QF contracts lowers cost to Utah but increases cost to both California and Oregon and was considered by Oregon parties to be a partial offset to allocating a larger share of the Mid-Columbia Contracts to them. The cost of the QFs to Oregon declines significantly after 2012, while the benefit from the Mid-Columbia Contracts remains substantial through the forecast period.

Q: What is the projected cost to Utah from use of the Revised Protocol?

A: CCS Exhibit 1.8 displays the cost impact in $000 of each of the Revised Protocol's cost components from the currently used method for each of PacifiCorp's six jurisdictions, including Utah. The years displayed in CCS Exhibit 1.8 and all following exhibits are Scottish Power fiscal years (FY). Scottish Power's fiscal year begins in April and ends in March. As you can see, the 2005 through 2009 NPV of the Revised Protocol to Utah ratepayers approaches $115 million. The cost varies between $25 and $36 million per year over this time period. It begins to decline in 2010. In 2011, Utah's

Revised Protocol revenue requirement is projected to be lower than Utah's Rolled-In revenue requirement. The ten-year NPV difference drops from the five-year NPV by roughly $1 million. The fourteen-year NPV declines to approximately $95 million.

In percentage terms, the projected cost increase to Utah is roughly_____________________________ of Rolled-In revenue requirement over the first five years. It drops to _________________________________over ten years and to ___________over fourteen.

Q: Compared to Rolled-In, why does the Revised Protocol first lead to a higher revenue requirement and later to a lower revenue requirement?

A: The reason is in the construction of the Company-owned hydro adjustment. The Embedded Cost Differential hydro adjustment is based on the difference in two calculations, (1) the total cost of the hydro resources including post-merger costs which include the hydro relicensing costs,[23] and (2) the total cost of the rest of the system minus the Qualifying Facilities. Initially, the difference between the two calculations reduces costs to the former PPL states and increases costs to the former UPL states. As the relicensing costs of the hydro facilities kick in, the hydro resources are forecast to be more costly than the system average, reversing the effect. Under Rolled-In, Utah pays its share of the relicensing costs. Under the Revised Protocol, Utah is shielded from these costs.

Q: Is the benefit to Utah in the later years from using the Revised Protocol permanent?

A: Possibly not. As the relicensing costs are amortized and the new hydro capital costs are depreciated, the relative costs of the system versus the hydro resources may again reverse, generating a benefit to the former PPL states and imposing costs on the former UPL states. The size and sign of the hydro

[23] In all past allocation methods, the costs of new investments in joint-use plant were rolled-in.

adjustment depends on the difference in average system costs versus hydro costs. Any factor that changes either will alter the size of the adjustment.

Q: Have you prepared an exhibit that compares the projected Utah revenue requirement results from Revised Protocol to various benchmarks?

A: Yes. CCS Exhibit 1.9 compares forecasts of Utah's revenue requirement based on the Revised Protocol with benchmarks that the Committee considers to be appropriate. Because previous allocation methods did not include a seasonal resources category, and because the Committee believes a case for seasonal resources might be supportable on the principle of cost causation, I first removed the effect of the seasonal resources from the Revised Protocol. I then considered three different benchmarks.

The first benchmark is one-half the difference between Rolled-In and Modified Accord. The Committee understands this to be the essence of what became termed the "Fair Share." I was first introduced to the concept on 2 November 2000 while attending a PRPPP meeting in Portland. A PacifiCorp representative, Dr. Rodger Weaver, made a presentation to that group regarding the existing allocation hole and the Company's proposal to close it. At that time the difference between Modified Accord and Rolled-In was approximately $55 million per year but was forecast to disappear within five or six years. The concept that Dr. Weaver proposed was for each state to pick up a proportional share of the cost allocation gap, which at that time would have required a roughly 2% increase in each state's revenue requirement. The two states using Rolled-In, Utah and Idaho, would pick up more of the non-transmission costs and the states using Modified Accord more of the transmission costs to achieve this goal.[24] Dr. Weaver indicated that the 2%

[24] Because premerger plant is divisionally assigned under Modified Accord, the former PPL states are shielded from some of the transmission cost. In developing the fair share allocation factors, the Company was anticipating that an RTO would take over PacifiCorp's transmission function. Since its costs would be rolled-in, the former PPL states would, by PacifiCorp's participation in an RTO, pick up a larger share of transmission costs than they do under Modified Accord, leaving non-transmission costs for Utah and Idaho to shoulder to achieve a proportional sharing.

revenue requirement increase would decline over time as the difference between the two allocation methods diminished.

Mathematically, if each state picks up one-half the difference between its Rolled-In revenue requirement and its Modified Accord revenue requirement, the same result is achieved as using end-driven allocation factors to achieve a proportional sharing. A proportional sharing of the existing allocation gap is the understanding that the Committee held when we indicated during the MSP that we would accept no more than a fair sharing of the existing allocation hole if there were a cost-causal reason to do so.

Almost four years have passed since the introduction of the Fair Share concept, and the difference between the Rolled-In results and Modified Accord results has shrunk as expected and discussed in the PRPPP, thereby shrinking the Fair Share revenue requirement. As you can see from CCS Exhibit 1.9, the five-year NPV approaches $18 million, or ______________________ of Rolled-In revenue requirement; the ten-year NPV approaches $24 million, or ______________________ of revenue requirement; and the fourteen-year is slightly more than $26 million, or ______________________ of revenue requirement. The cost of the Revised Protocol clearly overwhelms this benchmark.

The second benchmark is the hydro endowment as defined in the Utah Dynamic Alternative.[25] As part of the Utah Dynamic Alternative, Utah parties had proposed a hydro adjustment that would approach a fair sharing of the existing allocation hole. Its construction was similar to the Modified Accord hydro adjustment except that the fuel-cost adjustment was based on the difference between hydro and premerger steam plant rather than all steam plant, and hydro relicensing costs were included. Because of its construction, this hydro adjustment would eventually disappear, either as a result of the retirement of premerger thermal plant or when the cost of relicensing swamped

[25] The Committee agreed to consider this time-limited hydro adjustment because the load growth issue had not yet been studied extensively and at that time we thought there could be cost leakage from our load growth to the other PacifiCorp states.

the benefit of the fuel adjustment. It was thought that it would be smaller than the fuel adjustment in Modified Accord and should, therefore, approach a "fair-sharing" of the existing allocation hole.

This hydro endowment disappears in 2009. Therefore, the five-year, ten-year, and fourteen-year NPV all equal just under $25 million. Again, the cost of the Revised Protocol overwhelms this bench mark.

The third bench mark is one-half the difference between Rolled-In and the Modified Accord fuel adjustment. In studying the load growth issue, it became apparent that when the costs of plants are assigned on a divisional basis, a growing state is shielded from picking up its share of these premerger plant costs as its load grows. By removing the assignment of premerger plant from the Modified Accord calculation, just the benefit from the lower operating cost of the hydro resources to the former PPL states is captured. The fuel adjustment therefore benchmarks the magnitude of the hydro adjustment included in the Modified Accord method. One-half the difference between the fuel adjustment and Rolled-in would be a sharing of the Modified Accord hydro adjustment. Again, sharing the existing allocation gap, as expressed by Fair Share, was the concept behind this benchmark.

This approach adds from $7.5 million to just under $9 million per year over the fourteen-year period to Utah's revenue requirement. The five-year NPV approaches $26 million, or ____ of Rolled-In revenue requirement; the ten-year NPV is just under $50 million, or ____ of Rolled-In revenue requirement, and the fourteen-year NPV is roughly $62.5 million, or _______________________________________ of Rolled-In revenue requirement.

To summarize, the Revised Protocol impact greatly exceeds any of these three benchmarks, particularly in the first five years.

Q: Have you prepared an exhibit that illustrates the revenue requirement differences between Revised Protocol and Modified Accord?

A: Yes. You can see this in CCS Exhibit 1.9. CCS Exhibit 1.9 shows differences from Utah's Rolled-in revenue requirement. The five-year NPV difference using Modified Accord adds $35.7 million to Utah's revenue requirement compared to $114.8 million using Revised Protocol; the Revised Protocol increase to revenue requirement is more than 3 times greater than Modified Accord. The ten-year NPV difference using Modified Accord adds $47.5 million compared to $113.7 million using Revised Protocol; the Revised Protocol increase to revenue requirement is more than double that of Modified Accord. And the fourteen-year NPV is $52.5 million using Modified Accord compared to $95 million using Revised Protocol; the Revised Protocol increase to revenue requirement is still nearly double that of Modified Accord.

Q: Earlier in your testimony you raised the issue of the durability of the Revised Protocol. What factors may conspire to undermine its durability?

A: The four cost-shifting components of the Protocol appear to be designed with an eye to benefiting Oregon. The combination of the Company-owned hydro adjustment, the specification of the Mid-Columbia Split, and the situs assignment of the existing QF costs provide Oregon with a balanced package that generates modest net benefits over the study period. As can be seen in CCS Exhibit 1.8, replacing Modified Accord with the Revised Protocol produces a percentage decline in Oregon's five-year NPV of 1.36%; a percentage decline in Oregon's ten-year NPV of .69%, and a percentage decline in it fourteen-year NPV of .41%. The revenue requirement increases that Oregon may experience in the later years are quite small. The QF contract cost disappears in the later years, and the benefit from the Mid-Columbia Contracts balances the cost of hydro relicensing. The largest revenue requirement increase that Oregon sees in any year is .54% in 2018.

The Revised Protocol benefits Washington as well. While Washington benefits even more than does Oregon in the early years because the situs assignment of QFs helps them (they do share in out-of-market QFs like they did under Modified Accord), they do not do as well as Oregon in the later years. The Mid-Columbia Contract offset to Company-owned hydro relicensing costs is smaller because they get a smaller share than Oregon of the two Mid-Columbia Contracts.

The other two former PPL states do not fare as well as either Oregon or Washington. They do not receive the benefit of the low cost Mid-Columbia Contracts which they did under Modified Accord (these contracts were rolled-in and so they received a share of their benefit), and they bear a larger share of the hydro relicensing costs in the later years than they would under Modified Accord (these costs would have been rolled-in and shared by all jurisdictions). In addition California now has to bear the full cost of its QFs which it did not under Modified Accord. As a result, California's revenue requirement increases in all years, even in the years that the Company-owned hydro is generating benefits. In any one year, California's smallest revenue requirement increase is roughly 1.5%. In other years, its revenue requirement increases by upwards of 4%. While Wyoming benefits in the early years, it begins taking on costs in the later years.

Whether either California or Wyoming would be willing to continue to bear these costs in the later years is not clear. While California's loads are small and its rejection of the Revised Protocol could be ignored, Wyoming is PacifiCorp's third largest jurisdiction. Its continued support, therefore, is not inconsequential.

However, the Committee's fundamental concern with durability relates to the packaged nature of the Revised Protocol. The two components that cause the largest cost shifts have characteristics that have already been rejected by past Utah Commissions as not meeting the principle of cost-causation. Therefore, if the future unfolds differently from expectations, it is possible that unintended consequences may lead to pressures that the package cannot withstand.

Q: Please generally describe the key features of the Stipulation.

A: The stipulation provides partial rate mitigation from the cost of the Revised Protocol in the early years and provides additional protections in the event that the Revised Protocol turns out to be more costly to Utah in the later years than indicated by PacifiCorp's forecasts. Finally, it provides the right incentives to the Company to properly address, through the Standing Committee, aspects of the Revised Protocol that the Committee is not comfortable with.

Q: Please describe the Rate Mitigation Measures included in the Stipulation.

A: The Rate Mitigation Measures have two components, a Rate Cap and a Rate Premium. The Rate Cap assures that Utah customers will pay the lesser of the Revised Protocol or some fixed percentage above what Utah's Rolled-In revenue requirement would otherwise be. Rates are capped at 1.5% of Rolled-In for 2006 and 2007. The cap drops to 1.25% for 2008 and 2009. After 2009, if Utah's Revised Protocol revenue requirement exceeds or is expected to exceed 1% of Rolled-In, PacifiCorp may initiate a reexamination of interjurisdictional allocations. Until resolved, Utah's revenue requirement would be no greater than 1% of Rolled-In through 2014.

If the Revised Protocol delivers lower rates than Rolled-In the later years, the Company has the opportunity to collect a Mitigation Premium. If 100.25% of Revised Protocol is no more than 101% of Rolled-In in the years 2010 – 2012, the Company may receive a mitigation premium of .25% of Revised Protocol.

Q: Previous exhibits included forecasts for 2005. Why is not 2005 part of the Rate Mitigation Measures?

A: PacifiCorp indicated that it could not get new rates in place before FY 2006 which begins 1 April, 2005. CCS Exhibit 1.10 links PacifiCorp's fiscal year to the calendar year and provides a color coded key to the Rate Mitigation Measures.

Q: Please explain the additional protections provided by the Stipulation.

A: First, the stipulation requires the Company to continue to file Rolled-In results of operation throughout the nine-year period and makes clear that Rolled-In is the benchmark for evaluating the Revised Protocol.

Second, the Rate Mitigation Caps limit customer risk should the agreement turn out not to be durable or should the Revised Protocol produce actual results that significantly differ from current forecasts so that the beneficial future where Revised Protocol forecasts produce a smaller revenue requirement than Rolled-In is never reached.

Third, if the Revised Protocol revenue requirement results are greater than Rolled-in in the later years of the Stipulation, the Company is incented to open a new allocation case before Utah customers bear the full cost of the unanticipated costs of the Revised Protocol.

Finally, the most important protection is provided by the clause: “a party’s execution of this Stipulation will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude, in good faith, that the Revised Protocol no longer produces results that are just, reasonable, and in the public interest.”[26]

The Utah Commission has established a compelling precedent regarding the equity and efficiency of a rolled-in allocation method and has spoken with a clear and consistent voice regarding allocation in all cases that have dealt with cost allocation beginning with its approval of the 1989 merger.[27] In the 1990 rate case, the first rate case following the merger, the Utah Commission established rolled-in as the standard method for determining Utah’s revenue requirement consistent with single-system planning and operation and the principle of cost causation. It used the results of the Consensus method to add a $72.74 million lump sum amount to Rolled-In to meet the objective of merger fairness. It agreed to use the Consensus results because of the fair, open, and deliberative process and the agreement achieved by state staffs. The Commission made clear, however, that the fairness adjustment was not a cost-based transfer.[28]

Given the Commission-established precedent, the Committee interprets the just and reasonable clauses in the Stipulation and Protocol to mean the following: if the Revised Protocol ever results in Utah’s revenue requirement

[26] A nearly identical clause is included in the introduction to the Revised Protocol.

[27] See Docket Nos. 87-035-27, 90-035-06, 97-035-01, 97-035-04, 99-035-10, and 01-035-01 for discussion of interjurisdictional allocation. See also, Docket No.89-035-10.

[28] Report and Order issued December 7, 1990, paragraphs 5, pages 13-14.

exceeding Rolled-In after the time in which the forecasts indicate that the Revised Protocol should produce results that are lower than Rolled-In, the method would no longer be just and reasonable and in the public interest.

Q: Do you have any recommendations to protect Utah customers beyond the timeline established in the Stipulation?

A: Yes. In this docket, the Commission should reassert that Rolled-In is the standard for determining just and reasonable rates and is the permanent benchmark against which the Revised Protocol or any other apportionment method will be evaluated. It should order the Company to report Rolled-In results of operation beyond the 2014 time period required by the Stipulation. If at any time after 2014, the cost of the Revised Protocol were to exceed 101% of Rolled-In, the Commission should open a docket to investigate the justness and reasonableness of the interjurisdictional allocation method.

Q: What is the basis for recommending 1% above Rolled-In as the threshold for opening a docket to reexamine the use of the Revised Protocol?

A: This is the same threshold included in the Stipulation and agreed to by parties to the Stipulation; therefore it appears to have general support.

Q: You stated that the Stipulation provides the right incentives to the Company to properly address, through the Standing Committee, other parts of the Revised Protocol that the Committee is not comfortable with. Please explain.

A: We believe that the current treatment of seasonal resources is not principled and unfairly burdens the summer season (shifts cost to Utah). Because shareholders could absorb the difference between the Rate Mitigation Cap and the Revised Protocol revenue requirement outcomes, we think the Company is incented to support a more balanced approach regarding the seasonal resource category in discussions before the Standing Committee than they otherwise might.

Q: Based on current forecasts, what is the expected cost of the Revised Protocol with the Rate Mitigation Measures?

A: CCS Exhibit 1.11 shows the forecasted cost of the Revised Protocol with the Rate Measures and compares it to other bench marks. This exhibit's timeline has been adjusted from the previous exhibits to be consistent with a 2006 start date. The added cost to Utah customers averages roughly $20 million per year for five years. It then begins to decline significantly, producing lower revenue requirements than Rolled-In after 2012. (The Rate Mitigation Premium delays the benefit to Utah from using Revised Protocol by two years.) The four-year NPV approaches $68 million, or 1.4% above Rolled-In; the nine-year NPV increases to approximately $75.5 million, or .6% above Rolled-In; and the fourteen-year NPV declines to $55 million, or .3% above Rolled-In. Shareholders pick up roughly $31 million in the first five years. This declines to $22.3 million if the Company receives the Mitigation Premium.

Q: The cost of the Revised Protocol with the Rate Mitigation Measures is still substantially greater than the benchmarks described above and displayed in CCS Exhibit 1.11. Given the cost, why is the Committee supporting the Revised Protocol and Stipulation?

A: In order to implement its current and future IRP Action Plans, PacifiCorp must make substantial investments in new resources and infrastructure. The Committee decided that providing the Company with the greater cost recovery certainty that an agreement among the states would provide was important at this point in time. By resolving this impasse between the states and PacifiCorp, the Committee expects the Company to manage its core utility business in a manner that produces the least-cost, low-risk mix of resources for customers and to spend far less time worrying about its regulatory risk.

Q: Please explain in greater detail PacifiCorp's need to make significant resource and infrastructure investments?

A: The PacifiCorp system remains resource deficit, and the deficit is particularly severe in the Company's eastern control area. As system load continues to grow and power purchase contracts expire, the system requires substantial resource additions over the next 14 years. The MSP analysis incorporated the results of the 2003 IRP load forecast, with a subsequent modification that projected higher Utah load growth and lower growth in the western states. The load growth in that forecast, contract terminations and projected retirements over the next fourteen years would require nearly 6000 MW of new capacity.[29]

Based on MSP model forecasts, system revenue requirement is projected to nearly double over the next 14 years as the 2003 IRP Action Plan is implemented. Utah's revenue requirement is projected to more than double. This can be seen in CCS Exhibit 1.12 which displays the state-by-state growth in revenue requirement assuming Rolled-In. CCS Exhibit 1.13 displays the same state-by-state information using the Revised Protocol.

Q: If the Commission ratifies the Revised Protocol and adopts the Stipulation, do you believe that the Company will make a better effort towards implementing a least-cost, least-risk IRP rather than one that it thinks has the greatest chance of cost recovery but at a higher cost to Utah customers?

A: That is our hope.

The Committee and the Division have been extremely concerned that the Company initiate an effective IRP to address its resource deficit. The Committee contends that the West Valley Lease and the Gadsby addition exemplify decisions that were not necessarily in the best long-term economic interest of Utah customers, but rather were the result of a planning delay brought on by deregulation and by cost recovery concerns resulting from Oregon's stated policy direction even prior to the passage of SB 1149.

After the western market meltdown in 2000-2001, and beginning with its seventh IRP cycle, the Company made significant improvements in its planning process. It moved its IRP function from its Regulation Department to its Commercial and Trading Department to "ensure integration with PacifiCorp's resource procurement, trading and risk management functions," and it committed the necessary personnel and other resources to develop an

[29] This total consists of roughly 5000 MW to meet 4300 MW of load growth and reserve margin, 400 MW of net contract terminations, and 600 MW of retirements.

innovative approach and conducted a strong public process.[30] The result was a vastly improved resource acquisition strategy that diversified fuel, environmental, and market risk. However, despite the significant improvements the Committee commented to the Commission that "management's concern for shareholder recovery appear to be influencing resource acquisition thereby resulting in continued exposure to the short-term market and a more costly acquisition strategy than necessary."[31]

The Committee hopes that, by providing the Company with a single apportionment method and a comprehensive guide to interjurisdictional allocation, the Company will focus on effective planning and management of customer risk.

Q: You have stated that the Commission has a well-developed record regarding the cost-causal basis for Rolled-In. Since the Revised Protocol deviates from Rolled-In, it does not meet this ratemaking principle. Do you have a principled basis for supporting the Revised Protocol with the protections of the Stipulation?

A: The Stipulation can be supported using the principle of gradualism. In the first phase of the 1990 rate case the Commission determined that Utah's rolled-in revenue requirement was $530.02. It added $72.74 million to achieve merger fairness. The lump sum addition was 13.7% of Utah's rolled-in revenue requirement.

Fourteen years and a lot of history have passed. In order to resolve this issue, the Committee is willing to accept a 1.5% addition to Rolled-in in the next two years that is forecast to decline to the equivalent of Rolled-in the 2012

[30] PacifiCorp, Integrated Resource Plan 2003, p.161.

[31] Committee of Consumer Services, Recommendations of the Committee of Consumer Services regarding the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan 2003, Docket No. 03-2035-01, 31 March 2003, pp. 2-3.

timeframe. This provides for a 22-year transition to Rolled-In, still within the 30-year outer limit set by the Commission to achieve Rolled-in.[32]

If Utah's Revised Protocol revenue requirement were not forecast to decline to below Rolled-In levels, the Committee could not support the Revised Protocol with the protections of the Stipulation. Again, as mentioned earlier in testimony, should the Revised Protocol revenue requirement exceed Rolled-In in the future, the Committee would expect interjurisdictional allocations to be revisited.

Q: Did the Committee compare the costs of the agreement to the cost of no agreement?

The Committee did not. The difficulty in conducting such an analysis is the uncertainty of the alternative. While we have forecasts of the cost of the Revised Protocol, we do not know the cost of the alternative because the alternative itself is unknown. We don't know what would transpire absent an agreement, and it is this uncertainty that we are hedging against in supporting the Revised Protocol with the protections of the Stipulation.

While it is possible that there would be no negative consequence to Utah customers from not achieving a single cost-allocation method, it is also possible that the Company could be significantly harmed, thereby imposing costs to Utah customers.

Q: Please explain.

A: Although Oregon parties are adamant regarding their right to the exclusive benefits of the hydro resources including the Mid-Columbia Contracts and the need for protection from Utah's load growth, we think the Company has the

[32] In the 1989 merger order, the Commission established 10 years as the goal to achieve Rolled-In but allowed for the possibility of a longer transition. In its 7 July 1998 Report and Order in Docket No. 97-035-04, in establishing the size of the remaining fairness adjustment, the Commission "reaffirmed the phase-out bounds set in the December 7, 1990 Report and Order in Docket No. 90-035-06, and … decided to employ them." The Commission then discusses a ten-year phase out and a 30-year phase out, bounding the transition between 10 and 30 years. (See Public Service Commission, Determination of the Value of the Fairness Adjustment, Docket No. 97-035-01, 7 July 1998, p. 11.)

ability to advocate Rolled-In or some other allocation method designed to narrow the existing allocation hole and win based on an evidentiary record.

At the other extreme, should the Oregon Commission adopt a version of the Hybrid and Utah did not change its method, there is the potential for harm to the Company depending on fuel and market prices. Under some scenarios the Company would do well, under others it could be harmed significantly, possibly harming customers.

The problem is that we do not know what would occur if we do not have a single cost allocation method, therefore, the Committee is supporting the use of the Revised Protocol with the protections provided by the Stipulation.

Q: Do you have other comments regarding your support of the Stipulation?

A: Yes, ultimately, the Committee considers the need to enter into this Stipulation to be the fallout from deregulation. It was Oregon's deregulation that drove the Company to file the SRP which evolved into this process. And it is the Committee's perspective that it was because of deregulation that the Company did not acquire resources in a timely manner to meet its Eastern loads. And it is deregulation that played havoc with the western market just as the PacifiCorp system became deficit, particularly on the summer peak in the eastern control area. Had the Company not been short, or had the market not disintegrated, neither customers nor shareholders would have been harmed by the excess power costs incurred during that long year and half. Resources other than Gadsby or West Valley would have been built or acquired and Utah's load growth would have been less of an issue.

As it is, the Company opened a Pandora's Box with its regulatory risk management, its drive for a global solution, and what we see as accommodating the northwest demands at a time when resource additions in the eastern control area are imperative. Utah has not been successful in getting the Company to strongly advocate merged costs for a merged system. We support the Stipulation now in order to close the box and get on with business.

<u>Concerns with the Revised Protocol Requiring Monitoring and or Standing Committee Action</u>

Q: You mentioned in your summary that you desired to inform the Commission of areas of concern and/or incompleteness in the Revised Protocol. Would you like to address these now?

A: Yes. While we are supporting the Revised Protocol in order to provide the Company with the right incentives to implement an effective IRP, we are concerned that elements of the Revised Protocol may have the unintended consequence of creating planning distortions. As briefly mentioned earlier, the size of the Embedded Cost Differential Hydro adjustment is determined by the factors that determine relative average costs of the hydro resources versus system resources. This construction could lead to incentives to prefer other than least-cost system resources for beneficiaries of the hydro adjustment. Resources that increase average system cost would increase the size of the hydro adjustment and vice versa. While the Committee hopes that this will not become a problem, we think the possibility does require monitoring.

Q: Are there potentially other planning disincentives.

A: Yes, I address a similar concern in the next section on Standing Committee issues.

Q: What is the general charge to the MSP Standing Committee?

A: Section XIII.B.4. of the Protocol provides that:

> The MSP Standing Committee will consider possible amendments to the Protocol that would be equitable to PacifiCorp customers in all States and to the Company. The MSP Standing Committee will have discretion to determine how best to encourage consensual resolution of issues arising under the Protocol. Its actions may include, but will not be limited to: a) appointing a committee of interested parties to study an issue and make recommendations, or b) retaining (at the Company's expense) one or more disinterested parties to make advisory findings on issues of fact arising under the Protocol.

Q: What issues does the Protocol specifically defer to the MSP Standing Committee?

A: The Protocol specifies possible future roles for the MSP Standing Committee in recommending changes to the "provisions related to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts" (IV. B.1.c) and any required refunctionalization of transmission assets (Section V), as well as major immediate roles in three areas:

- Seasonal Resources;
- potential cost shifts related to load growth; and
- allocation of costs related to customers who permanently opt out of new PacifiCorp power supply.

I discuss these three areas in order below, and provide some additional information regarding the charge to the MSP Standing Committee in CCS Exhibit 1.14.

Q: Do you have any concerns regarding Standing Committee activity?

A: The Committee would note that effectively protecting Utah customer interests in front of the Standing Committee may require a sustained level of effort and the commitment of considerable staff resources.

Q: What specific assignments does the Protocol give to the MSP Standing Committee regarding Seasonal Resources?

A: Section IV.A of the Protocol provides:

> The MSP Standing Committee will review Seasonal Resources criteria and allocation. Items to be considered include the seasonal patterns of Resource operation to determine seasonality, the treatment of associated off-system sales, the value of operating reserves provided from Seasonal Resources, criteria to define seasonal Exchange Contracts and methods for allocating the costs of seasonal exchange returns.

The urgency of this review is emphasized in Section XIII.B.5.

> The MSP Standing Committee has the immediate assignments of… reviewing Seasonal Resources criteria and allocation, including seasonal patterns of Resource operation to determine seasonality, treatment of associated off-system sales, the value of operating reserves provided from Seasonal Resources, criteria to define seasonal Exchange Contracts and methods for allocating the costs of seasonal exchange returns.

Q: Why is the MSP Standing Committee charged with reviewing "the seasonal patterns of Resource operation to determine seasonality"?

A: The Protocol (section IV.A) defines "Seasonal Resource" as:

(a) a simple-cycle combustion turbine (SCCT) owned or leased by the Company;

(b) any Seasonal Contract, which is further defined as a Wholesale Contract pursuant to which the Company acquires power for five or less months during more than one year; and

(c) Cholla Unit 4.

These are arbitrary definitions with little consistency or underlying rationale. The definitions do not provide a consistent, operational basis for determining whether existing resources are seasonal, let alone the range of potential new resources. Development of comprehensive, consistent criteria for seasonality of resources will reduce the risk of disagreements regarding the allocation of resources as they come on line, and reduce the incentives for states reviewing an IRP to prefer specific resources based on the inconsistencies in the definitions of Seasonal Resources.

Hence, the Protocol charges the MSP Standing Committee with developing comprehensive criteria for identifying Seasonal Resources. In the process, the MSP Standing Committee will need to better delineate what constitutes a separate contract or resource, to which the seasonal tests would be applied, and develop mechanisms for allocating the costs and benefits of seasonal exchanges and sales.

Q: Why is the MSP Standing Committee charged with reviewing the treatment of off-system sales associated with Seasonal Resources?

A: In the current Protocol, the cost of a purchase that meets the definition of a seasonal resource is allocated seasonally, but off-system sales with the same characteristics are not allocated seasonally. This asymmetry unfairly charges the costs of resources differently from the benefits. It may also be inefficient, leading to sub-optimal planning decisions.

Q: Why is the MSP Standing Committee charged with reviewing "the value of operating reserves provided from Seasonal Resources"?

A: The Protocol identifies Seasonal Resources and allocates their costs across months, based on monthly energy generation. Some resources, such as

SCCTs, may provide substantial benefits to the PacifiCorp system when they are not generating much or any energy, especially in the form of operating reserves. Having quick-start SCCTs available may allow PacifiCorp to dispatch its steam and hydro resources more efficiently, without holding back as much capacity in operating reserves.

Q: What specific assignments does the Protocol give to the MSP Standing Committee regarding potential cost shifts related to load growth?

A: Section IV. E of the Protocol provides as follows:

> In concert with the 2004 IRP cycle, the Company and parties will analyze and quantify potential cost shifts related to faster-growing States.…No later than nine months after filing the 2004 IRP, the Company, in consultation with the MSP Standing Committee and other parties, will file a report with the Commissions regarding this issue. Included in this report will be a description of one or more options for a structural protection mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction.
>
> The MSP Standing Committee is charged with developing one or more ameliorative mechanisms that could be implemented in a timely manner in the event that the studies show a material and sustained net harm to particular States from the implementation of the IRP. The MSP Standing Committee should consider the impact of load growth in light of all other relevant factors. Potential mechanisms to be studied include tiered allocations, treatment of Seasonal Resources, a structural separation of the Company, temporary assignment of the costs of some new Resources to fast-growing States, and the inclusion of measures of recent load growth in the computation of allocation factors.

Section XIII.B.5. emphasizes the immediacy of this task:

> The MSP Standing Committee has the immediate assignments of… developing one or more mechanisms that could be implemented in a timely manner in the event that load growth studies show a material and sustained net harm to particular States from the implementation of the IRP…

Q: Why is the MSP Standing Committee charged with developing structural protection mechanisms?

A: Oregon parties remain unconvinced that Utah is fully paying for its growth and want assurance that there is no possibility for a cost shift. The speaker for the

Oregon Coalition, Marc Hellman, told MSP participants at the last meeting held in Boise on April 27-28, that Oregon was not willing to pay a single dollar for Utah load growth. In order to provide that level of assurance, the northwest parties believe a structural mechanism is required. They demanded this of the Company.

Q: Does this provision cause the Committee concern?

A: It does. The Committee is concerned that this provision undermines the durability of the Revised Protocol. By supporting the Revised Protocol and Stipulation we are supporting increases to our revenue requirement. The reason the Committee is willing to consider this is to maintain the benefits of single system planning and operation over the long-run. If the Revised Protocol proves not to be durable, Utah will have paid a considerable premium above Rolled-In for benefits that do not transpire.

Q: Did you take steps to insulate Utah from such an outcome?

A: Yes. The Committee added the language "…in the event that the studies show a material and sustained net harm to customers in any jurisdiction." The Committee understands that the Company will work with northwest parties to develop such a mechanism, but it will not support its use without compelling evidence of materiality of harm.

Q: Do you have a recommendation for the Commission regarding this item.

A: Yes. The Commission should require the Company to provide it with the opportunity to review the materiality of harm before the Company may can propose a structural mechanism before the Standing Committee.

Q: What specific assignments does the Protocol give to the MSP Standing Committee regarding Direct Access or opt-out?

A: Section X.A.2 of the Protocol provides

> Loads of customers permanently choosing Direct Access or permanently opting out of New Resources – Where the Company is no longer required to plan for the load of customers who permanently choose direct access or permanently opt out of New Resources, such loads will be included in Load-Based Dynamic Allocation Factors for all Existing Resources but will not be included in Load-Based Dynamic Allocation Factors for New Resources acquired after the election to permanently choose Direct Access or opt out of New Resources. An effective date for this process will be established at such time as customers permanently choose Direct Access or opt out, and this process will be implemented under the guidance of the MSP Standing Committee.

Q: Why is this issue referred to the MSP Standing Committee?

A: The Protocol lays out only the most general rules for the treatment of loads "permanently choosing Direct Access or permanently opting out of New Resources." All the details remain to be resolved.

Q: Are there many details to be resolved regarding customers who are not permanently moved to Direct Access?

A: No. The Protocol's treatment of this situation is reasonably complete. For interstate allocation, the Direct Access load will be treated as any other firm jurisdictional load, and the allocation of costs between the Direct Access customers and full-service load will the responsibility of the individual state.

Q: So what issues must the MSP Standing Committee resolve regarding permanent Direct Access or other customer opt-out from New Resources?

A: The major remaining issues for these situations, which I will call "permanent opt-out," include:

- Setting rules to ensure that customers who permanently renounce rights to cost-of-service generation do not return their loads to PacifiCorp's regulated load;
- Establishing mechanisms for monitoring the permanence of opt-out, to protect the interests of all states;
- Defining the conditions under which a separate opt-out cohort will be created, and when customers who opt out over a period of time will be treated as a single cohort;

- Constructing an operational definition of New Resources;
- Determining the method for computing the demand and energy attributed to the opt-out load for allocating Existing Resources;
- Setting rules for allocating energy costs and sales revenues to opt-out loads;
- Determining how energy will be allocated to the opt-out load and treated for ratemaking, so that the opt-out customers or PacifiCorp receive the appropriate benefits of the energy associated with the costs allocated to the opt-out load;

Committee Reservations

Q: The Committee is supporting the Revised Protocol with the protections of the Stipulation, but it sounds as if you have considerable angst. Is this true?

A: Yes. We have considerable angst for a number of reasons, but three are paramount.

First, the Company assumed the interjurisdictional allocation risk. At the time of the 1989 merger, PacifiCorp accepted the risk of interjurisdictional allocation differences. This is well documented in testimony, post-merger briefing, and the Utah Commission's merger order. When Scottish Power acquired PacifiCorp it also assumed the risk of differences in allocation methods.[33] The Committee understands that the Company has a right to manage its regulatory risk through a process such as this. However, the lack of durability of the original agreement concerns us. The Committee finds it difficult to trust the veracity of any of the Company's current assurances in other forums, given what we perceive to be a breach of trust on this issue.

Second, Utah ratepayers have paid a considerable sum over the years. The understanding coming from the original merger was that the UPL customers would share their excess energy, extensive transmission system, and rapidly growing Wasatch front with the energy short PPL. As a result the merged Company could

[33] See for example, Public Service Commission, Docket No. 98-2035-04, Report and Order, Scottish Power\PacifiCorp Merger, 23 November, 1999, p. 8.

become a highly competitive seller of power and would lower power costs for all its customers.[34] In exchange we were to receive the benefit of merged costs, including the benefit of the hydro resources. The Utah Commission set a ten year goal to achieve that end.

In 1990, the Commission established Rolled-in as the Utah allocation method but allowed for an addition to Rolled-in in order to achieve merger fairness.[35] In 1997, the Commission revisited the allocation issue, reaffirmed Rolled-In as Utah's allocation method, and ended the fairness adjustment through a five-year phase out. The Commission determined the dollar amount that Utah customers should pay, to achieve merger fairness. The size of the remaining fairness adjustment was based on the midpoint between a ten-year straight-line to Rolled-in and a thirty-year straight line to Rolled-in.[36] Thus Utah customers have already paid for a twenty-year transition. Utah customers used a refund due them in the 1997 test-year rate case to buy out the amount determined in phase two of the allocation case, and adjusted in the 1997 rate case, and completed the transition to full roll-in January 1, 2001.[37]

We kept our part of the bargain. The northwest states received the benefit of our energy and our transmission system. They received the benefit of our relatively faster load growth throughout the era of resource surplus. Some parties in Oregon and Washington now want to permanently block our achieving the bargain for which we have paid. These parties had their opportunity to be heard at the time of the merger and they made their cases. The Oregon Commission approved the merger despite that opposition, and language in that merger Order allows for the possibility of full roll-in within five years. The Committee is distressed to be in the position of having the Company, which assumed the risk of allocation differences knowing,

[34] The concern at the time was to develop new markets. In addition to our energy and our infrastructure we provided a retail market and access to a vast wholesale market.

[35] The Commission appears to have considered itself to have "adopted" Rolled-in in 1990. In Docket Number 97-035-04, April 16, 1998, pp. 15-16, in referring to history the Commission says: "First, we have adopted no cost apportionment method but Rolled-in."

[36] See Report and Order in Docket No. 97-035-04, July 7, 1998, p. 11.

[37] See Report and Order in Docket No. 97-035-01, March 4, 1999, pp. 55-62.

what was expected in Utah, to come to Utah asking us to ante up once again to solve the regulatory risk imposed on them by Oregon parties.

Finally, we see no principled basis for supporting any type of permanent resource endowment for any group. The copious rain that falls in the northwest, and the ample hydro resources that result from it, may have both social and economic impacts on the citizens of that region, but they are not essentially different from those that result from the draining of desert aquifers and increased airborne pollutants in Utah. The PacifiCorp system uses the mix of resources to provide beneficial service to all its customers jointly.

Q: Does this conclude your testimony?

A: It does.